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IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-12-0504 **STAFF'S NOTICE OF FILING DIRECT TESTIMONY (RATE DESIGN)**

Staff of the Arizona Corporation Commission ("Staff") hereby files the Direct Testimony of Howard Solganick (Rate Design) in the above docket.

RESPECTFULLY SUBMITTED this 12th day of July 2013.

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Commissioner
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Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONALBE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-04204A-12-0504

DIRECT

TESTIMONY

(RATE DESIGN)

OF

HOWARD SOLGANICK

FOR THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 12, 2013

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-12-0504

Mr. Solganick's testimony reviews and analyzes UNS Electric, Inc.'s ("Company") class cost of service study ("CCOSS") and the various rate design proposals of the Company. Mr. Solganick has also filed direct testimony on behalf of the Arizona Corporation Commission ("Commission") Utilities Division ("Staff") regarding the Company's Lost Fixed Cost Recovery proposal on June 28, 2013.

Mr. Solganick's testimony presents Staff's recommendations based on a review of the Company's application and responses to Staff's and other parties' data requests.

Mr. Solganick recommends that the Company's CCOSS not be given significant weight in the revenue allocation process. Mr. Solganick's testimony also describes the economic, social, historical and other factors that may affect customers and be the basis of the Commission's determination of the allocation of an increase in revenue.

Mr. Solganick recommends that the Company's proposals to consolidate and redesign its rates be modified. Mr. Solganick recommends that the residential customer charges be reduced and an additional block be added to the standard residential rate. For non-residential rates, Mr. Solganick recommends specific customer charges.

Staff recommends that the Company's proposals for a 100 percent demand ratchet, partial service requirements and the elimination of Super Peak rates be rejected. Instead, Mr. Solganick recommends a process to address the Super Peak rates.

Mr. Solganick recommends that the Company's proposal for an extended summer On-Peak period within its Time of Use rates be replaced by an On-Peak period of six hours in order to encourage greater participation by residential and non-residential customers. Mr. Solganick also recommends that a customer education program be developed for time-of-use rates.

Mr. Solganick recommends that the Company's CARES (lifeline) proposal be modified to retain the present level of support and to minimize the impact on certain customer subclasses due to the change in structure proposed by the Company.

Mr. Solganick recommends that the Company's proposed miscellaneous fees should be revised.

Mr. Solganick recommends that the final rate design be developed through a cooperative process among the parties that reflects either a settlement or the Commission's decision.

Mr. Solganick recommends that the Commission require the Company to provide additional class cost of service information in its next rate case.

I. INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, PA 19047. I am performing this assignment under subcontract to Blue Ridge Consulting Services, Inc.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("Commission").

Q. Did you file direct testimony in this proceeding?

A. Yes. I filed direct testimony regarding the Company's Lost Fixed Cost Recovery ("LFCR") proposal on June 28, 2013.

II. DIRECT TESTIMONY

Q. What is the purpose of this testimony?

A. My testimony analyzes UNS Electric Inc.'s ("Company") class cost of service study ("CCOSS") and the Company's proposed rate design. I recommend changes to the proposed rate design, time of use periods, lifeline rates and various tariff changes.

Based on my review of the Company's application, supporting testimony, and responses to data requests, I make the following recommendations:

- The Commission should direct the Company to revise its proposed rate designs to reflect the Staff's recommendations covering customer charges, miscellaneous charges and other elements.

- The Commission should direct the Company to revise its Time of Use ("TOU") rate design to reflect the Staff's recommendations including changing the proposed Summer On-Peak period to encourage greater participation.

- The Commission should direct the Company to revise its CARES (low-income and medical) rate design to reflect the Staff's recommendations to continue the existing level of benefits, reduce the impacts on customers and consolidate the CARES rates within the residential rates.

- The Commission should direct the Company to supplement the record on lighting and interruptible rates.

- The Commission should reject the Company's implementation of proposed changes to Partial Requirements Service.

- The Commission should reject the Company's proposal to remove its Super Peak TOU rates and instead direct the Company to develop a revised program.

- The Commission should direct the Company to file in its next rate case a series of cost of service studies employing the Average and Excess ("A&E-NCP") and Average and Peak ("A&P") and other cost allocation methodologies primarily related to power supply.

Class Cost of Service

Q. Has the Company provided a class cost of service study?

A. The Company provided its CCOSS based on the Test Year (twelve month period ended June 30, 2012).[1] This schedule provides the individual class returns for the Company's six major customer classes.

Q. What is the purpose of a fully allocated cost of service study?

A. Just as the rate case process studies each element of the Company's operations to determine the overall cost to operate the Company efficiently and effectively, a fully allocated cost of service study attempts to determine the individual cost to serve each customer class and subclass. A fully allocated cost of service study is intended to assist the Commission to allocate revenue requirements among customer classes.

[1] UNS Filing Schedule G

Q. How does a regulator use the cost of service study?

A. Because customer classes use the utility's system on an interrelated or shared basis, regulators have historically used a fully allocated cost of service study as a guideline to allocate revenue among classes. Additionally, regulators typically also consider economic, social, historical and other factors that may affect customers when determining revenue allocation.

Q. Are there limitations to a cost of service study?

A. Yes, a cost of service study involves judgment and decisions on the part of the practitioner in assigning costs to the various customer classes. In some situations, decisions are made to use a particular allocation factor for a particular account. In other situations, data used to develop an allocation factor are not always complete and/or timely and the practitioner must deal with the resulting uncertainty. Consequently, the cost of service study acts as a guide in revenue allocation and in formulating rate design.

Q. Have you reviewed the CCOSS presented by the Company?

A. Yes. The CCOSS was provided as Schedules G-1 through 7. I performed a review of the allocations, developed and reviewed the answers to Data Requests by Staff and other parties and conducted an informal technical conference with the Company to understand certain aspects of the CCOSS.

Q. Did the Company adjust or normalize its revenues?

A. The Company used a Test Year (twelve months ending June 30, 2012) and then adjusted it to reflect more normal or appropriate (from the Company's viewpoint) conditions. The

Company made revenue adjustments for weather normalization and customer annualization.[2]

Q. What is the Company's forecast of its capacity plans for the short-term future?

A. The Company currently owns peaking generation and purchases significant capacity and energy under a number of power purchase agreements.[3] Additionally, the Company is forecasting the need to review its commitments beginning in 2015 as its existing power purchase commitments expire.[4]

Q. What allocators does the Company use for its power supply expenses within the CCOSS?

A. For Other Production Plant the Company uses the DPROD allocator (A&P), which is classified exclusively as demand.[5] For Other Production Expenses the Company uses the EFUEL allocator, which is classified exclusively as energy.[6] For Purchased Power Expenses the Company uses the EFUEL allocator for energy charges, which is classified exclusively as energy.[7]

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[2] Jones Direct 6:12 and 9:22
[3] 2013 UNS IRP, Page 52
[4] 2012 UNS IRP, Pages 57 and 58
[5] UNS Schedule G-3, Sheet 5, lines 14-20
[6] UNS Schedule G-4, Sheet 2, line 18
[7] UNS Schedule G-4, Sheet 2, line 29

Q. What is the effect of the Company's decision to allocate Other Production Plant and Purchased Power differently?

A. The Company is effectively purchasing some of its capacity capability within the Purchased Power Fuel Adjustor Clause ("PPFAC") along with the energy purchased and allocates those costs using the EFUEL allocator. Company owned peaking generation is allocated on a more traditional basis using the DPROD allocator for rate base and the EFUEL allocator for fuel. By allocating all of its purchased power costs (capacity and energy) on an energy basis, the results of the CCOSS may be skewed between classes that have different load factors.

Q. Has the use of the A&P allocator been approved by the Commission?

A. No. Although the Company supports its use of an A&P allocator by stating, "This method has also been approved by the Commission in previous UNS Electric rate cases."[8], the Company was unable to provide any orders referencing the Commission's approval of the A&P allocator.[9]

Q. Did the Company provide any other versions of its CCOSS using a different allocator for power supply?

A. No. Another power supply allocator that may be appropriate is A&E-NCP as this methodology considers the dual elements of both demand (capacity requirements) and average load (energy requirements) as does the A&P methodology. Staff requested a version of the CCOSS using this allocator and the Company objected to the request as being overly burdensome and requiring the Company to generate additional CCOSS models not already in its possession.[10]

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[8] Jones Direct 17:6
[9] UNS Response to STF 2.28
[10] UNS Response to STF 2.27

Q. Is the development of the A&E-NCP allocator overly burdensome or costly?

A. No. With some planning this allocator can be developed when other CCOSS allocators are constructed. Most CCOSS models can easily substitute one allocator for another. An all energy allocator and a coincident peak allocator (using four peaks "4CP") are developed as the A&P allocator is developed.

Q. Did you examine the results of the CCOSS provided by the Company?

A. I reviewed the Company's Exhibit G, the CCOSS prepared by the Company, and found a result that caused me to perform additional investigation. The Unitized Rate of Return on Rate Base ("UROR") of the Mining class is shown as -1.865.[11] In light of the negative UROR I was then surprised that the Mining class received a revenue increase percentage closer to the overall percentage increase.

I contacted the Company and through an informal technical conference it confirmed that the CCOSS uses load and other allocation information from the Test Year.[12] However, the CCOSS includes significant revenue adjustments, which in the case of the Mining class reduce the annual revenue by over 40 percent.[13]

Q. What is the source of the 40 percent reduction in Mining class revenues?

A. The Company has indicated that one of its Mining customers added a turbine for self-generation that "drastically changed their load and demand."[14]

[11] Schedule G-1 Sheet 1, Column G
[12] Technical Conference May 21, 2013 and email May 28, 2013
[13] Schedule G-1 Sheet 1, Column G, Rows 20 and 21
[14] UNS Response to STF 2.58

Q. Does the Company's adjustment of revenues impact any other classes?

A. Yes, it impacts every class to varying extents. The Company's CCOSS adjusts revenues for each class to account for weather normalization, customer annualization and known changes such as the Mining class. The class impacts are:[15]

Class	Base Revenues Present Rates ($)	Revenue Adjustments ($)	Adjustment
Total Company	168,523,613	-6,333,095	-3.76%
Residential Service	80,803,473	-230,878	-0.29%
Small General Service	10,609,847	927,189	8.74%
Large General Service	47,853,711	-57,771	-0.12%
Large Power Service	17,104,043	-2,349,203	-13.73%
Mining	11,701,004	-4,786,258	-40.90%
Lighting	451,535	163,825	36.28%

Q. What is the result of this adjustment of revenues without a corresponding adjustment of load and other allocations from the Test Year?

A. The Company's CCOSS as presented in schedule G has a mismatch that renders its UROR results inappropriate to use for revenue allocation. This mismatch is the result of using adjusted revenues but not adjusting the Test Year loads or other factors. For example, the Mining class revenues were reduced to reflect the addition of a turbine for self-generation but the loads for the class were not adjusted downward. Thus the Mining class was allocated costs based on the Test Year but has lower revenues than the Test Year, which would lower the class rate of return.

[15] UNS Schedule G-1, Sheet 1, lines 20 and 21

Q. Can the CCOSS be rehabilitated to provide one of the factors that could assist the Commission in determining the appropriate revenue allocation among classes?

A. Yes. The Company has indicated that the revenue adjustment was accomplished on line 21 of Schedule G-1. In response to the discussions between Staff and the Company on May 21st, the Company indicated that the reduction in load "did not impact the results of the CCOSS substantially.[16] However I am not comfortable with this situation, because of the magnitude of the change in the Mining class revenues.

Q. Does the CCOSS provide unit cost information to support rate design?

A. The Company provided Schedule G-6-1 labeled Revenues and Unit Cost. After my initial review I was concerned that the number of residential customers was misstated compared to other data. Staff then requested a reconciliation of the customer count.[17] Staff also asked for unit cost data including a return component at the overall rate of return and the Company provided this information.[18]

Q. Did the Company perform a system loss study for use in the CCOSS?

A. No. The Company indicated that it had not completed a system loss study for the test year but instead losses were estimated from TEP seasonal loss data and Citizens line loss data.[19]

Q. Do you have any recommendations covering the Company's CCOSS?

A. The Company has provided only limited information concerning the relative positions of the various customer classes. While a CCOSS is only one input into the Commission's

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[16] UNS email dated May 28, 2013
[17] UNS Response to STF 5.1
[18] UNS Response to STF 2.43 updated May 21, 2013
[19] UNS Response to STF 2.23

decision on revenue allocation the Company's CCOSS should provide answers and not develop further questions during a case. Therefore, I recommend that the Company be ordered to provide the following information in its next rate case:

- The Company should provide power supply allocators including at a minimum A&P, A&E-NCP, energy only and 4CP, along with a simple "switch" to select one of these allocators and produce the CCOSS. This submission would allow all parties to understand the impact of the power supply allocator using a consistent data source. This is important because the Company has relied on the A&P allocator without any decision by the Commission.

- The Company should explore and provide a CCOSS that allocates its power supply costs on a demand and energy basis. This submission would allow all parties to understand the impact among classes that is presently unavailable because all purchased power costs (but not peaking generation) are allocated on an energy basis in the CCOSS. This analysis is important because over time the Company may change its methods of obtaining capacity and energy.

Q. Why do you recommend the various power supply allocators listed above?

A. The allocators listed above are customary used for allocation of power supply. These allocation methodologies are among those defined in the NARUC Electric Cost Allocation Manual (1992) and reflect a range of possible methods.

- A coincident peak ("CP") allocator such as 4CP allocates costs to customer classes according to the load of the customers classes at the time of the utility's highest demands in each of four months. Other similar methods include a single hour CP, 12 CP (twelve months), which may be chosen based on the annual load shape.

- An energy only allocator allocates costs to customer classes according to customer class energy consumption, which is effectively average class demand. This method focuses on energy usage and ignores peak demand.

- Average and Peaks allocator is a combination of average load (energy) and peak load (demand).

- An average and excess ("A&E") allocator such as A&E-NCP is another commonly used method that combines energy and demand characteristics.

Each of these allocators approach energy and demand in different ways and will have a different impact on high versus low load factor customer classes. My four suggestions provide a range of allocators (all to be provided by the Company from consistent data and calculations) that allow the parties to a case to advocate and debate from their various points of view and provide the Commission with a record for their decision.

Q. Is the Company's CCOSS appropriate for its use as a guideline to develop a revenue allocation proposal?

A. The items I have summarized above cause me concern about the use of results from the CCOSS. Therefore, I do not recommend that the CCOSS provided by the Company be given significant weight in the revenue allocation process.

Revenue Allocation

Q. What non-cost considerations should the Commission consider?

A. The Commission should consider the relative positions of the classes along with the qualitative issues such as economic conditions for consumers, the business climate and past practices when deciding what portion of a revenue increase is allocated to each class. Also the size of the classes limits how much the Commission can move a class at the conclusion of any single rate case. For example, the Large General Service class is more than four times larger than either the Small General Service or Mining classes. The Residential class is more than seven times larger than the Small General Service class and almost equal to all other classes combined.[20]

[20] Schedule G-1, Line 20 Total Electric Revenue From Sales

Rate Design

Q. What underlying principles do you use for rate design?

A. For residential and small general service customers, I lean towards simplicity where possible. This would include a limited number of rate schedules and riders. I recognize that one rate schedule does not fit all customers and that schedules that encourage limiting or shifting peak consumption have real value both for customers, system planners and longer term cost reduction.

For delivery (distribution) rates, I recommend gradually shifting from volumetric to customer and demand charges as supported by cost of service principles. This recognizes that delivery services are not generally based on volumetric (energy) parameters but vary based on the number of customers and their demand.

Q. Please summarize the Company's rate design proposal.

A. The Company's rate design objectives are to simplify and modernize its rates,[21] to better align the Commission's policies with the Company's need for fixed cost recovery,[22] and reduce existing cross-subsidies between customer classes[23].

Q. What was the Company's primary concern in developing its rate design proposals?

A. As I understand the Company's approach, the focus was on evaluating the potential impacts on customers by developing a full understanding of how these changes would affect revenues.[24] The Company describes its efforts to determine the appropriate level of billing determinants.[25]

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[21] Jones Direct 20:6
[22] Jones Direct 20:26
[23] Jones Direct 20:27
[24] Jones Direct 21:11
[25] Jones Direct 21:13

Q. Is this focus on revenue impact sufficient to support a wide range of rate design changes?

A. Evaluating the revenue impact is not the only concern when rate design is substantially changed. There are impacts on the customers' behavior and operations that should be considered during the rate design process to minimize unintended consequences. While the following list is not exhaustive, it includes a range of sources of information about customers that should be considered.

- Customer Alternatives
  - Competitive Fuel Forecasting[26]
  - End Use Forecasting[27]

- Customer Information
  - Formal Commercial & Industrial Survey Process[28]
  - Appliance Saturation Study[29]
  - Consumption versus Income[30]

- Rate Studies
  - Non-Coincident Peak ("NCP") Data[31]
  - System Losses[32]
  - Marginal Cost[33]

Q. Did the Company perform any of the above studies or have such information?

A. In response to Staff data requests, the Company indicated that these items were not readily available or only limited information was available. [The footnotes above provide references.]

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[26] UNS Response to STF 2.13
[27] UNS Response to STF 2.11
[28] UNS Response to STF 2.10
[29] UNS Response to STF 2.12
[30] UNS Response to STF 2.39
[31] UNS Response to STF 2.22
[32] UNS Response to STF 2.23
[33] UNS Response to STF 2.31

Q. Are these items essential to accomplish the scope of the rate design envisioned by the Company?

A. Having all of the items is not essential, but each item provides information about customer options and potential reactions to a new or modified rate. The lack of this information increases the possibility that some important aspect will be overlooked or cannot be readily evaluated by all parties.

Q. Is the Company's unit cost analysis in Schedule G-6-1 useful in evaluating its proposed customer charges?

A. Many of my concerns about the CCOSS do not apply to the direct customer costs. The Company also updated Schedule G-6-1 and the update should be used as a point of comparison.[34] The Company's information shows direct customer costs, an amount that includes meters, billing and collection meter reading costs and the service.[35] The Company has indicated that it does not use either a minimum sized system or zero intercept methodology to allocate portions of the distribution system (such as poles, wires, transformers) to the customer component.[36] Conversely, it is inappropriate to consider in the basis for the monthly Customer Charge shared costs such as production and transmission that do vary with the demand the customer places on the system and those costs should be collected in a charge that varies with usage (absent a demand charge).[37] Therefore, a Customer Charge somewhat above the direct unit cost would be appropriate.

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[34] UNS Response to STF 5.1 (d), Line 31
[35] Jones Direct 16:26, and Schedule G-3 and G-4
[36] UNS Response to STF 2.29
[37] UNS Response to STF 5.1 (d), Lines 2 and 3

Q. What changes does the Company propose for the Residential Service (Rate RES-01) rate?

A. The Company is requesting an increase in the customer charge from $8.00 to $10.50.[38] Additionally, the energy charges also are proposed to increase.[39]

Q. What changes does the Company propose for the TOU Residential Service (Rate RES-01 TOU) rate?

A. The Company is requesting an increase in the customer charge from $8.00 to $12.00 for TOU customers,[40] the elimination of the Shoulder Peak period,[41] and changes to the On-Peak hours.[42] The Company also is requesting the elimination of its Super Peak TOU rates.[43]

Q. What are the residential customer costs?

A. The Company's information shows that direct customer costs are $8.03.[44] This amount includes meters, billing and collection meter reading costs and the service.[45]

Q. Do you support the changes to the RES-01 residential rate?

A. I suggest the following modifications of the Company's proposal:

- The existing rate design including the first tier (up to 400 kWh) should be retained.
- The Customer Charge should be set first by an increase up to (based on the class' revenue allocation) $10.00 (RES-01) and $11.50 (RES-01 TOU) for TOU customers. This is consistent with the Tucson Electric Power ("TEP") Settlement.

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38 Jones Direct 29:17
39 UNS Schedule H-3, Page 1
40 Jones Direct 29:18 [Schedule H-3, Page 1 shows $12.50]
41 Jones Direct 23:17
42 Jones Direct 23:18
43 Jones Direct 23:21
44 UNS Response to STF 5.1, Line 31
45 Jones Direct 25:24

- For non-TOU customers, a new tier at 1,000 kWh should be developed to offer a breakpoint that includes approximately 58% of summer bills and 76% of winter bills.[46] This is consistent with the TEP Settlement.

- The existing inverted rate structure should be retained.

- The revenue allocated to the Residential class should be collected first by an increase in the customer charge up to the level proposed here, with the remainder (if any) recovered by increased energy charges. Applying the revenue increase to the Customer Charge first will increase recovery of fixed charges and reduce the impact of the recommended LFCR mechanism.

Q. What is the Company's Opt-Out option for those customers who do not want an AMR meter that uses radio frequency for meter reading?

A. The Company has added Meter Opt-Out language to the Rate RES-01 to charge the Special Meter Reading fee each month and a one-time Meter Change-Out fee.[47] The charges proposed by the Company are both $26.00, an increase from the existing $20.00.[48] This option is specifically not available to CARES rate customers.[49]

Q. Is the Company's Opt-Out proposal appropriate?

A. No. In this situation a customer is requesting non-standard service and should pay for the incremental cost of providing service, otherwise all other customers have to pay for the additional work requested by a single customer. However, the Company's proposal assumes that each customer served in this manner is separate and that no economies of scale exist even though this customer's request may be able to be scheduled with other work. Further, the Company is not offering the Opt-Out option to CARES customers, without any support for that proposal. I do agree with the Company that TOU service cannot be supplied to Opt-Out customers for technical and operational reasons.[50]

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[46] UNS Response to STF 11.3
[47] Exhibit CAJ-8, Sheet 101-1 and Jones Direct 31:11
[48] Exhibit CAJ-7 - Tariff Original Sheet 801
[49] Exhibit CAJ-8 – Tariff Original Sheet 101-1
[50] Exhibit CAJ-7 – Tariff Original Sheet 101-1

Q. What process do you propose for Opt-Out customers?

A. I recommend that the additional meter reading services requested by Opt-Out customers be priced to encourage the Company to productively handle Opt-Out service. For example the Company's tariff describes the process for customers who require special meter reading.[51] One productivity measure that could be encouraged would be the use of meter reading by customers that would support a lower monthly charge. As described in the tariff the Company would read the meter at least once every six months. Under either type of meter reading, the Company still has costs for special data entry.

Q. What charges do you propose for Opt-Out services?

A. This issue may be addressed in the Commission's generic docket for Opt-Out service (Docket No. E-00000C-11-0328). However, should the Commission wish to address the issue in this matter, I recommend that the Automated Meter Opt-Out tariff language developed in the TEP Settlement be adopted for UNS. This language which applies to non-TOU residential customers, including lifeline customers (CARES), provides for the one-time meter change-out fee and a $10.00 meter reading fee that is reduced to $5.00 if an accurate and timely self read is provided by the customer. Adoption of this language will reduce confusion between the affiliated companies for both customers and the Company's customer service representatives.

Q. What changes does the Company propose for the Small General Service (SGS-10) rate?

A. For Small General Service customers, the Company is requesting an increase in the customer charge from $12.50 to $14.50 with the TOU subclass an additional $2.00 higher at $16.50.[52] Additionally, the energy charges also are proposed to increase.[53] This non-

[51] UNS Proposed Tariff Section 10 Meter Reading
[52] Jones Direct 32:8

demand class will be limited to customers with a maximum imputed demand of 500 kW. The Company is also proposing to add a third tier to the SGS rate for consumption in excess of 7,500 kWh.

Q. Is the Company's increase in the customer charge for Small General Service customers (SGS-10) appropriate?

A. Some customers using this rate may have characteristics similar to a residential customer and this rate also does not include a demand charge. The unit cost information in Schedule G-6-1 indicates that customer costs for the Small General Service Class are $16.56.[54]

Q. Do you support the changes to the SGS rate?

A. I suggest the following modifications of the Company's proposal:

- The existing rate design should be retained.
- The new tier requested for the Rate SGS-10 at 7,500 kWh should be implemented with a requirement that the Company notify the customer that it may have a lower rate on another rate schedule. This one-time notification should occur within 3 billing cycles of the first time an SGS customer uses over 7,500 kWh.
- The existing inverted rate structure should be retained.
- The customer charges requested by the Company are appropriate. The revenue allocated to the SGS class should be collected first by an increase in the customer charge up to the level proposed by the Company, with the remainder (if any) recovered by increased energy charges on a proportional basis between blocks. Applying the revenue increase to the Customer Charge first will increase recovery of fixed charges and reduce the impact of the recommended LFCR mechanism.

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[53] UNS Schedule H-3, Page 1
[54] UNS Response to STF 5.1, Line 31

Q. What changes does the Company propose for the Large General Service (LGS) rate?

A. For Large General Service customers, the Company is requesting an increase in the customer charge from $16.00 to $50.00 with the TOU subclass an additional $2.00 higher. Demand charges are proposed to increase from $14.12 to $14.52 per kW.[55] Additionally, the energy charges also are proposed to increase.[56] This class will have a minimum demand of 20 kW, and the existing cap of 1,000 kW will be removed.

Q. How can customers subject to the minimum demand of 20 kW be protected?

A. The Company adjusted its billing determinants to reflect that customers below 20 kW would switch to the SGS rate. There are approximately 240 customers who could be affected.[57] Consistent with this analysis, the Company should be required to provide written notice to each affected LGS customer of the 20 kW minimum demand, its financial impact and the alternative of switching to another rate. This switch should be without cost or penalty to the customers affected.

Q. Is the Company's increase in the customer charge for Large General Service customers appropriate?

A. The unit cost information in Schedule G-6-1 indicates that customer costs for the Large General Service Class are $74.51.[58]

Q. Do you support the changes to the LGS rate?

A. I suggest the following modifications of the Company's proposal:

- The existing rate design should be retained.

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[55] Jones Direct 32:13
[56] UNS Schedule H-3, Page 1
[57] UNS Response to STF 11.7
[58] UNS Response to STF 5.1, Line 31

- The customer charges requested by the Company are appropriate. The revenue allocated to the LGS class should be collected first by an increase in the customer charge up to the level proposed by the Company, with the remainder (if any) recovered by increased demand and energy charges. Applying the revenue increase to the Customer Charge first and then a portion to demand charges will increase recovery of fixed charges and reduce the impact of the recommended LFCR mechanism.

Q. What rate changes does the Company propose for the LPS customer class?

A. For Large Power Service (Rate LPS) customers, the Company is requesting a change from two customer charges ($372.00 below 69 kV and $407.00 at 69 kV and above) to an increased single customer charge of $1,500.00.[59] Demand charges are proposed to increase from $21.73 and $15.80 to $24.37 and $18.37 per kW.[60] Additionally, the energy charges are proposed to decrease slightly.[61] This demand class will continue to have a minimum demand of 500 kW.

Q. Is the Company's increase in the customer charge for Large Power Service customers appropriate?

A. The unit cost information in Schedule G-6-1 indicates that customer costs for the Large Power Service Class are $1,181.58.[62]

Q. Do you support the changes to the LPS rate?

A. I suggest the following modifications of the Company's proposal:

- The existing rate design should be retained.

- The customer charge should be set at $1,200. The revenue allocated to the LPS class should be collected first by an increase in the customer charge up to the level proposed here, with the remainder (if any) recovered by increased demand and

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[59] Jones Direct 32:21
[60] UNS Schedule H-3, Page 2
[61] UNS Schedule H-3, Page 2
[62] UNS Response to STF 5.1, Line 31

energy charges. Applying the revenue increase to the Customer Charge first and then a portion to demand charges will increase recovery of fixed charges and reduce the impact of the recommended LFCR mechanism.

Q. Is the Company's proposed change to a 100% demand ratchet[63] appropriate?

A. At present, LGS customers are subject to no demand ratchet while LPS customers are subject to an 11 month 100 percent demand Ratchet. Additionally, the Company has not provided an analysis of the bill impact on low load factor LGS customers. The bill comparison provided assumes a 75 percent load factor and only presents the information on an energy basis.[64] Therefore, the change to a 100 percent demand ratchet is not appropriate at this time. A change for LGS customers should only be accepted if the Company provides a bill impact analysis that demonstrates that the change will not greatly impact LGS customers with low load factors. If this cannot be demonstrated then LGS customers should not be subject to a demand ratchet at this time.

Conversely, the LPS customers are already subject to a 100 percent demand ratchet. Attempting to be consistent between the LGS and LPS customers or the TEP Settlement at 75 percent is problematic at best. While a 100 percent demand ratchet may have a theoretical basis, a more reasonable and measured approach would be to not change the demand ratchet for both the LGS and LPS rate at this time.

Q. How is the Company proposing to change its TOU rates?

A. The Company is proposing to eliminate the Shoulder period in its TOU rates to be more consistent with its costs and easier for the customer to understand.[65] For all rate classes

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[63] Jones Direct 35:13
[64] Schedule H-4, Page 4
[65] Jones Direct 37:4

the Company is proposing a summer On-Peak period of 12 Noon to 8 PM and two winter On-Peak periods of 6 AM to 10 AM and 5 PM to 9 PM.

Q. Have you mapped out the Company's proposed changes to the TOU rate periods?

A. To visualize the changes proposed I have generated the following table:

	Present UNS[66]	Proposed by UNS[67]	TEP Settlement[68]	Staff Recommended[69]
Time Period				
Summer				
Noon – 2 PM	Shoulder	On-Peak		
2 PM to 6 PM	On-Peak	On-Peak	On-Peak	On-Peak
6 PM to 8 PM	Shoulder	On-Peak	On-Peak	On-Peak
Winter				
5 AM to 9 AM				On-Peak
6 AM to 10 AM	On-Peak	On-Peak	On-Peak	
5 PM to 9 PM	On-Peak	On-Peak	On-Peak	On-Peak

All other periods and those not noted are considered Off-Peak.

Q. Do you support the changes to the TOU rate?

A. Yes and no. I agree with the Company proposal to have no On-Peak periods on the weekend and to eliminate Shoulder periods as confusing to customers. Although the Company has provided its rationale for the development of system wide TOU On-Peak periods I have concerns about the imposition of the broad hours proposed for residential customers who may decide that the additional four hours of On-Peak (previously Shoulder) are a burden that a customer might choose to avoid.

[66] Exhibit CAJ-9 Sheet 102-2 (RES), Sheet 202-3 (SGS), Sheet 205-2 (LGS) and Sheet 302-1 (LPS)
[67] Exhibit CAJ-8 Sheet 102-1 (RES), Sheet 202-1 (SGS), Sheet 205-1 (LGS) and Sheet 302-1 (LPS)
[68] TEP Settlement Sheet 102-1 (R-80), Sheet 203-1 (GS-76)
[69] Excludes Schools

Q. What summer On-Peak time periods do you recommend?

A. The Summer On-Peak period should be set at a maximum period of 6 hours. Staff suggests 2:00 PM to 8:00 PM. This covers all but two of the hours that the Company had requested for its On-Peak period and those hours were previously in the Shoulder period. This is consistent with the TEP Settlement. For customer education and customer service purposes consistency leads to lower costs while research is performed to determine if different periods would encourage participation. Also the summer load shapes for TEP and the Company are similar.[70]

Q. Why do you recommend summer On-Peak time periods that do not match the period suggested by the Company?

A. The Company's testimony provides less than a page to support its TOU proposal.[71] While its proposal is based on the TOU work performed in the recent TEP case[72], the goal is to obtain savings on energy costs and long-term peak load demand reductions. The Company's proposed On-Peak time period may fit the Company's operations but it may not encourage customers to shift to the new rates and may reduce the existing participation rates. Further the Company's power supply is market purchased.[73]

Q. Will a change in the On-Peak period change the rates charged to customers?

A. Yes, and only the Company has access to the billing determinants for different periods to calculate rates for the shorter period.

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[70] UNS Response to NUCOR 3.05
[71] Jones Direct 37:1
[72] UNS Response to NUCOR 3.02
[73] UNS Response to NUCOR 2.13

Q. What winter On-Peak time periods does Staff recommend?

A. Staff recommends a morning On-Peak period of 5AM to 9 AM to be consistent with the evening period.

Q. What parameters do you recommend to encourage customers to adopt TOU rates?

A. In light of this situation and the limited information available[74] about TOU customers including the costs they may incur to deal with broad On-Peak periods, I recommend:

- The Company should develop a customer education program for residential TOU customers including some means of estimating the potential cost savings.
- The Company should develop a customer education program to retain existing non-residential TOU customers and encourage new TOU customers. This may require training for its C&I representatives and/or the engagement of outside consultants.
- The Company should develop a research program to understand the benefits of TOU rates for the customer and the Company, including potential capacity and energy savings.

These recommendations are made to increase participation, understand why customers choose and stay on the TOU rate and measure the impact on energy costs and peak demand.

Q. The Company is proposing to eliminate its Super Peak rates.[75] Is this appropriate?

A. No. A critical peak rate can offer advantages to the Company and customers by targeting periods of high energy costs and/or capacity needs. I recommend that the Company retain its Super Peak rates but modify them to align with the revised TOU periods. Based on the Company's explanation of the marketing program,[76] I recommend that the program be revised and upgraded and potentially include more targeted marketing based on usage or

[74] UNS Response to NUCOR 3.02 and STF 2.54
[75] Jones Direct 23:21
[76] UNS Response to STF 2.40

load patterns, geography and demographics. The development of a revised and upgraded rate and its possible coordination with a similar rate for TEP may take some time. Also, there are no customers presently on the rates. Therefore, I recommend that the Company be allowed to develop the program and rates and file its proposal within six months of the effective date of the rate changes that result from this case.

Q. Has the Company addressed changes to TOU rates for schools?

A. I have not found any rate design testimony discussing school rates. The new rates are detailed in Schedule H-3 (page 3) and appear to be the same as proposed for SGS-TOU and LGS-TOU respectively, while the present rates are different. Exhibit CAJ-9 provides redlined school rates (SGS-10 TOU-S and LGS-TOU-S) that indicate no change in the On-Peak period and the shift of the former Shoulder period to Off-Peak. Also these revised rates do not appear in Exhibit CAJ-8.

Q. Did the Company provide any notice to schools about the proposed changes?

A. I was able to discuss the issue with the Company and they indicated that the Company had not provided any specific notice to schools nor had they engaged in any specific discussion of their proposal. The Company also confirmed my observations about the shift of the Shoulder period into the Off-Peak period and that the proposed school rates are the same as the proposed SGS and LGS rates. The Company also highlighted that the school rates were approved late last year and were acceptable to the schools at that time.[77]

Q. Is the Company's proposal for TOU rates for schools appropriate?

A. Based on the redlined rate schedules, I support the elimination of the Shoulder period and the transfer of those hours to the Off-Peak period. The rate changes proposed are

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[77] Telephone discussion with C. Jones on July 9, 2013

consistent with the SGS and LGS changes but are smaller because the present school rates are somewhat higher.

Q. What changes is the Company proposing for the Lighting Service rate?

A. The Company is proposing increases in the service charge and the per watt charge. The Company has modified the requirements for the advance for the installation of new facilities by making the advance non-refundable and setting the advance at $150.00. It is unclear if this advance is $150.00 per light or for all facilities, which could be a series of lights. The wattage charge does not define whether it is solely the lamp wattage or if a ballast load is included.

Q. Do you agree with the rate changes that the Company has proposed for the Lighting Service rate?

A. No. There is very limited testimony supporting the increase and only one vague sentence supporting the other changes. Further clarification is required before a recommendation can be made.

Q. Has the Company addressed changes to Interruptible rates?

A. I have not found any rate design testimony discussing interruptible rates. The new rates are detailed in Schedule H-3 (page 3) and appear to increase the customer charge by $2.00 along with a modest increase in the energy rate. Exhibit CAJ-9 provides a redlined interruptible rate ("IPS") that also includes an increase in penalty for failure to interrupt from $10.00 per kW to $25.00. The Company is also reducing the notice to interrupt from 15 minutes to 10 minutes and requiring the installation of remote disconnection capability. There is no change in the maximum 8 hour per day interruption period.

Q. Is the Company's proposal for Interruptible rates appropriate?

A. Without any support, the proposed Interruptible rates cannot be fully analyzed and a recommendation cannot be provided.

Q. Do you support the proposed changes to the Partial Requirements Service Rates?

A. Not at this time. The Company has not provided or performed any studies of this issue.[78] The testimony supporting this issue amounts to less than one page with no specific details.[79] In addition, the Company's proposed changes to the SGS, LGS, and LPS rate schedules regarding partial requirements provisions should not be made at this time.

Q. Please summarize the existing CARES (Lifeline) program.

A. There are two existing tariffs with six multi level percentage discounts and two fixed discounts. The Customer Charge is discounted and a further discount is applied on a sliding scale that decreases as consumption increases until it reaches a fixed dollar discount.[80] CARES customers are exempt from paying DSM surcharges.[81]

Q. What is the monthly consumption of a CARES customer?

A. On an annual basis the average consumption is 786 kWh.[82]

Q. Please describe the Company's CARES (Lifeline) proposal.

A. The Company is proposing to simplify and consolidate the existing CARES options down to a single tariff with a flat $13.00 per month credit.[83] This option would apply to low-income customers including medical low-income customers.[84] All CARES customers

[78] UNS Response to STF 2.50
[79] Jones Direct 38:16
[80] Jones Direct 52:6 and Exhibit CAJ-9 (no sheet number)
[81] Jones Direct 52:9 and Rider R-2
[82] UNS Schedule H-5, Page 1
[83] Jones Direct 52:8
[84] Jones Direct 52:10

would be moved to the RES-01 (non-TOU) rate.[85] CARES customers will continue to be subject to a limit of income below 150 percent of the federal defined poverty level.[86] All CARES customers will no longer be exempt from the DSM surcharge.[87]

Q. Is the Company proposing other changes to CARES rates?

A. Yes. The Company is also proposing to require CARES customers to re-qualify annually at the Company's request.[88]

Q. What is the overall value of the present CARES program?

A. The Company's testimony indicates that the combination of all these "benefits" totaled over $1.3 million during the test year for approximately 7,400 customers.[89]

Q. Have you reviewed the Company's proposal to revise the CARES programs?

A. I support the concept of the Company's recommendation to simplify the structure of the program and reduce potential confusion upon entry into and exit from the program.

To highlight the total value of the programs provided by other customers, the Company has proposed a simpler/clearer method that would allow a customer to take service on the existing residential rate (RES-01) and then have all of the benefits be provided through an embedded discount.[90] Additionally, when a CARES customer's fortunes improve there is no need to change the rate schedule; only the discount would be removed. These concepts are appropriate.

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[85] Jones Direct 53:21
[86] Jones Direct 54:12
[87] Jones Direct 52:9
[88] Jones Direct 54:6
[89] UNS Response to STF 2.70, STF 11.5 and Schedule H-5, Page 1
[90] Jones Direct 53:21

Q. **The Company has proposed applying the DSM surcharge to the CARES rate schedules, do you agree with this proposal?**

A. The Company's argument to include the DSMS adjustor for these customers is supported by concepts of rate clarity and simplicity. This is also consistent with the TEP Settlement.

Q. **Is the Company's CARES proposal appropriate when viewed on a customer impact basis?**

A. No. The Company provided estimates of the increase of the proposed rates as compared to current rates. Residential non-TOU customers are expected to see a 4.80 percent increase, while residential TOU customers are estimated to experience a 6.59 percent increase. CARES customers are estimated to experience a 9.98 percent increase.[91] Almost all of the CARES customers will experience percentage increases significantly higher than other customers. The following table summarizes this situation.[92] The bill comparison provided by the Company does not include the impact of applying the DSMS charge to CARES customers.

	Change to Total Bill (without DSMS Charge)				
	Percentage (%) Change			Dollar ($) Change	
	RES-01	CARES		RES-01	CARES
200 kWh	11.65	3.40		2.75	0.44
500 kWh	6.45	13.90		3.16	4.78
600 kWh	5.63	17.00		3.30	7.10
700 kWh	5.04	5.90		3.44	3.28
1000 kWh	3.97	9.30		3.85	7.46

[91] UNS Schedule H2-2
[92] UNS Schedule H-4, Page 1

Q. Why is the CARES customer being adversely affected by the transition?

A. The proposed $13.00 flat discount is inappropriate even when compared to the present situation. This is demonstrated by the example for a 1,001 kWh CARES bill.

		Present		Proposed	
		Rate	Savings	Rate	Savings
Customer Charge					
	RES-01	$8.00		$10.50	
	CARES	$3.50		$10.50	
			$4.50		$0.00
Discount @ 1001 kWh					
	CARES		$8.00		$13.00
Avoided DSMS @ 1001 kWh					
		$0.004382	$4.38		$0.00
Total Savings			$16.88		$13.00

Applying similar calculations, the present discounts at 600 kWh and 900 kWh are $17.47 and $16.36 respectively compared to the Company's proposal of $13.00.

Q. How do you recommend that the proposed CARES rates be revised?

A. It is appropriate to maintain the existing "benefit" of the CARES rates plus an offset for any increase granted. When the final rates are determined the Company should prepare its documentation to ensure all parties that the CARES "benefit" has not been significantly changed.

The transition from a multi-faceted, declining discount to a flat rate will impose varying changes for customers based upon their individual usage. The impact will also depend on the final revenue change. The impact of the new rates should be examined and if adverse impacts occur then the transition to the flat rate form may have to be modified to limit the dollar impact on CARES customers.

Q. The Company is proposing a number of miscellaneous tariff changes. Have you reviewed those proposals?

A. Yes. The Company proposes to move the fees to one location called "Statement of Charges" to make them easier for customers to locate.[93] I support that proposal.

Q. Have you examined the Company's proposed miscellaneous charges?

A. Yes. In response to a Staff data request the Company provided the background information related to the revised fees in the Statement of Charges (Sheet 801). The percentage increase for each fee appears high, ranging from 23% to as high as 83%.[94] Also the format of the Statement of Charges predates the TEP Settlement, which has a clearer, more customer friendly format.

Q. What are your recommendations for the Statement of Charges?

A. I recommend that the Company implement the format of the Statement of Charges presently used by TEP and the charges as detailed below. In some cases I am recommending a fee consistent with the TEP settlement as the service is performed within the common customer service function. For some charges that require trips and are of high volume the Company has provided its supporting data. For other charges the Company is assuming a two hour minimum call out, which may be appropriate but the

[93] Jones Direct 55:6
[94] UNS Response to STF 2.73

number of "units" per year is low and the cost is high compared to its affiliate TEP. UNS has not discussed charges for three phase service within its proposed Statement of Charges.

	Present UNS[95]	Proposed by UNS[96]	TEP Settlement[97]	Staff Recommended
Service Transfer Fee	Undefined	Undefined	$20.00	$20.00
Customer Requested Meter Re-read	$20.00	$26.00	$20.00	$25.00
Special Meter Reading Fee	$20.00	$26.00	$20.00	$25.00
Service Establishment and Reestablishment under usual operating procedures During Regular Business Hours – Single Phase	$30.00	$41.00	$32.00	$32.00
Service Establishment and Reestablishment under usual operating procedures After Regular Business Hours (includes Saturdays, Sundays and Holidays) – Single Phase	$75.00	$137.00	$57.00	$57.00
Service Reestablishment Other Than Usual Operating Procedures	$75	$150.00	$150.00	$150.00
Meter Test	$60.00	$74.00	$186.00	$74.00
Returned Payment Fee	$10.00	$10.00	$10.00	$10.00
Late Payment Finance Charge	1.5%	1.5%	1.5%	1.5%

Q. You have made a number of rate design recommendations that potentially interact with each other and are dependent on the final revenue increase, if any. How can the recommendations be implemented?

A. Unlike the revenue requirements process, rate design is much less linear and therefore it is less suited to having the final rates set by an adversarial process. While the parties can

[95] UNS Response to SFT 2.73 or existing UNS Rules & Regulations
[96] Exhibit CAJ-7, Sheet 801
[97] TEP Settlement, Attachment K, Sheet 801 and Sheet 801 effective July 1, 2013

each argue for their rate design methodologies, once those positions are accepted or rejected (either by settlement or the Commission's decision) the Company is in the best position to use its models and customer data to develop compliance rates. Under either process, all parties should have the opportunity to review the "final" rates, determine if the rate design positions were properly and accurately implemented and request alternate rates to better meet the decided positions before providing their approval. Through its technical conferences (formal and informal) and the data request process, the Company has demonstrated its ability to participate in an interactive process.

Q. Is there some risk when significant rate design changes are made?

A. Yes. Rate design changes may have unintended results for "outlier" customers that do not fit neatly into their apparent customer class. This risk is increased when customer research is limited or has not been performed.

I recommend that as provided for in the TEP Settlement, the Commission should keep the rate design portion of this case open for 12 months after the rate effective date to correct for unanticipated customer rate impacts that are determined to be inconsistent with the public interest.

Q. Does this conclude your testimony?

A. Yes.

Testimony - Howard Solganick

Arizona Corporation Commission
Case - Tucson Electric Power Company Docket No. E-01933A-12-0291 (December 2012 and January 2013)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Case - Arizona Public Service Company Docket No. E-01345A-11-0224 (November and December 2011)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Public Service Commission of Delaware
Case - Delmarva Power & Light Company Docket No. 10-237 (October 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and miscellaneous charges.

Case - Delmarva Power & Light Company Docket No. 09-414 (February 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and weather normalization.

Case - Delmarva Power & Light Company Docket No. 09-277T (November 2009)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered an analysis of a straight fixed variable rate design for small gas customers and implementation issues.

Case - Delmarva Power & Light Company Docket No. 06-284 (January 2007)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization or normalization.

Georgia Public Service Commission
Case - Atlanta Gas Light Company Docket No. 31647 (August 2010)
Client - Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered revenue forecast, cost of service, revenue allocation, rate design and other related issues.

Case - Atmos Energy Corporation Docket No. 27163 (July 2008)
Client - Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered rate design and other related issues.

Jamaica (West Indies) Office of Utility Regulation
Case - Electricity Appeals Tribunal (August 2007)
Client - Jamaica public Service Company, Ltd.
Scope - "Witness Statement" on behalf of the Jamaica Public Service Company Limited. This Statement covered issues relating to recovery of expenses incurred due to Hurricane Ivan.

Maine Public Utilities Commission
Case - Northern Utilities, Accelerated Cast Iron Replacement Program Docket No. 2005-813 (2005)
Client - Public Advocate of the State of Maine
Scope - Testimony covered an analysis of the program's economics and implementation.

Public Service Commission of Maryland
Case - Chesapeake Utilities Corporation Case No. 9062 (August 2006)
Client - Office of the Maryland People's Counsel
Scope - Testimony covered cost of service, rate design and other related issues.

Case - Baltimore Gas & Electric's (1993)
Client - As president of the Mid Atlantic Independent Power Producers
Scope - Testimony covered BG&E's capacity procurement plans.

Michigan Public Service Commission
Case - Consumers Energy Company Case No. U-15245 (November 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered cost of service, rate design and revenue allocation.

Case - Consumers Energy Company Case No. U-15190 (July 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy's gas revenue decoupling proposal.

Case - Consumers Energy Company Case No. U-15001 (June 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy and the MCV Partnership.

Case - Consumers Energy Company Case No. U-14981 (September 2006)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)

Scope - Testimony covered issues relating to the sale of Consumers interest in the Midland Cogeneration Venture.

Case - Consumers Energy Company Case No. U-14347 (June 2005)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope – Testimony covered cost of service and revenue allocation.

Missouri Public Service Commission
Case - AmerenUE Storm Adequacy Review (July 2008)
Client - KEMA/AmerenUE
Scope - Oral testimony covered KEMA's review of AmerenUE's system major storm restoration efforts.

Case - Veolia Energy Kansas City, Inc. File No. HR-2011-0241 (September 2011)
Client - City of Kansas City, Missouri
Scope - Testimony covered various aspects of the Company's tariff provisions and the impact on the City of Kansas City.

New Jersey Board of Public Utilities
Case - Cogeneration and Alternate Energy Docket # 8010-687 (1981)
Case - PURPA Rate Design and Lifeline Docket # 8010-687 (1981)
Case - Atlantic Electric Rate Case - Phases I & II Docket # 822-116 (1982)
Case - Power Supply Contract Litigation – Wilmington Thermal Systems Docket # 2755-89 (1989)
Case - NJBPU Atlantic Electric Rate Case - Phase II (1980-81) Docket # 7911-951 (Before the Commissioners of the New Jersey Board of Public Utilities)
Client - Employer was Atlantic City Electric Company.
Scope - The cases listed above covered load forecasting, capacity planning, load research, cost of service, rate design and power procurement.

Public Utilities Commission of Ohio
Case - The Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company Case 07-551-EL-AIR (January 2008)
Client - Ohio Schools Council
Scope - Testimony covers issues related to rate treatment of schools.

Case - The Application of the Columbus Southern Power Company 08-917-EL-SSO and the Ohio Power Company Case 08-918-EL-SSO (October 2008)
Client - Ohio Hospital Association

Scope - Testimony covers issues related to rates for net metering and alternate feed service and related treatment of hospitals.

Pennsylvania Public Utilities Commission
Case - York Water Company Docket No. R-00061322 (July 2006)
Client - Pennsylvania Office of Consumer Advocate
Subject - Testimony covered cost of service, rate design and other related issues, also supported the settlement process.

Case - Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2010)
Client - Municipal Sewer Group
Subject - Testimony covered capacity planning, construction, treatment of future load and associated revenue, cost of service, rate design, capacity fee and other related issues.

Case - Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2008)
Client - Municipal Sewer Group
Subject - Testimony covered cost of service, rate design, capacity fee and other related issues, also supported the settlement process.

Public Utilities Commission of Texas
Case - Determination of Hurricane Restoration Costs Docket No. 36918 (April 2009)
Client - CenterPoint Energy Houston Electric, LLC
Subject - Testimony covered the reasonableness of the client's Hurricane Ike restoration process for an outage covering over two million customers and a restoration period of 18 days.